23 February 2010

Mr Mike Buckley
General Manager
Network Regulation North Branch
Australian Energy Regulator
GPO Box 3131
Canberra ACT 2601

EUAA
ENERGY USERS ASSOCIATION OF AUSTRALIA

Dear Mike,

AER Draft Decision for the revenues controls to be applied to Energex and Ergon Energy in the period from 1 July 2010 to 30 June 2015

The Energy Users Association of Australia (EUAA) welcomes the opportunity to participate in this review and this opportunity to provide a submission to the Australian Energy Regulator (AER) on the AER's draft decision on the regulated revenue proposals from the Queensland DNSP's Energex and Ergon Energy for the period 2010-2015. Thank you for granting us a short extension of time in which to submit this.

In this submission we outline our views on the AER's decision and on the adverse impacts that the allowed expenditure increases would have on energy users. We particularly highlight the substantial tariff increases facing users if the AER accepts these proposals, these would range from 64% to 87% in nominal terms across the State and compounded over 2010-2015. Increases of this magnitude will adversely affect the operations of Queensland businesses that use electricity, including their operating costs, competitiveness (especially since many in the resources sector there are trade exposed), investment opportunities and ability to create and sustain jobs in the State. They will also affect the Queensland economy more broadly including its productivity, growth prospects and inflation pressures.

The EUAA looks to the AER to discharge its regulatory obligations reasonably and fairly so as to protect the interests of users by setting approved costs and energy volume forecasts at no more than efficient levels. To achieve this outcome fully and satisfy users, the AER must fulfil the requirement under the National Electricity Rules to consider all the capex and opex factors, including the requirement to benchmark these expenditures. The EUAA is disappointed that the AER did not fulfil its benchmarking obligations under the rules in the draft determination and we urge them to take the opportunity to do so in the final determination.

We urge the AER to fully consider the views of energy users throughout this review.

Yours sincerely,

Roman Domanski
Executive Director

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Submission to the Australian Energy Regulator on its Draft Decision for the regulated revenues to be applied to Energex and Ergon Energy in the period from 1 July 2010 to 30 June 2015

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Executive Summary

The AER is currently reviewing the revenue allowances for the two Queensland distribution businesses, Energex and Ergon, a process that will determine distribution prices in Queensland for the next five years. These comprise around 50% to 60% of the electricity charges paid by business users. For Queensland households they are around 65% of the cost of electricity. The AER's draft determination would, if confirmed, result in average distribution prices charged by Ergon and Enegex rising by 87% and 67% respectively over the five years from 1st July 2010. It would result in average distribution prices rising by 51% and 31% respectively in the first year of the regulatory period. Average electricity prices for electricity consumers in Queensland are likely to rise between 35% in Energex's territory and 45% in Ergon's territory over the regulatory period if the draft determination is confirmed by the AER.

This is an outcome that electricity users and the general economy in Queensland can ill afford, especially when (as the analysis in this submission shows), the costs that the AER appears willing to approve for Ergon and Energex are unnecessarily high and not efficient as required by the National Electricity Rules (NER). Nor would such an outcome meet the Electricity Market Objective in the National Electricity Law (NEL), which seeks to ensure that decisions made are *"in the long term interests of consumers of electricity",* including with respect to price.

The higher distribution prices resulting from the AER's draft decision would have adverse consequences on electricity users in Queensland. Their operating costs would increase, and they would have less capacity to sustain investment and jobs in the State. They would have to either pass on such cost increases to other industries and final consumers (if they can) or absorb them.

Industries in trade exposed sectors, such as mining, minerals processing and manufacturing, which are important in the Queensland economy, would be unlikely to be able to pass on the cost increases and their operations would be especially badly affected. Queensland businesses and households would also see impacts in terms of higher input prices and higher prices for many of the good and services they buy. As consumer and producer indices released following implementation of the AER's final determinations in New South Wales and Tasmania last year showed, the price impacts will also translate through into higher inflation. This was evident in the 2009 September quarter CPI figures where electricity prices were the largest single driver of the CPI increase both nationally, where they contributed to 21.7% of the 1.0 percentage point CPI increase, and in NSW and Tasmania, where they contributed 37% and 14% respectively, to those States CPI increases. Likewise, in the September quarter, the fastest growing component of producer prices was the electricity, gas and water component, which grew 12.1%.

The EUAA notes that the AER has reduced Ergon's proposed capex by some 16% and its opex by 19%, and Energex's proposed capex by 10.6% and its opex by 8%. However we note Ergon and Energex's capex would still increase by 53% and 78% respectively compared to the last regulatory period. Opex would increase by 25% and 12% respectively.

We attribute the AER's is failure to contain Ergon and Energex's price increases to three things:

- **A very high allowed cost of capital.** Privatised electricity distributors in Britain have recently accepted a proposal by their regulator for a cost of capital that is about half the level that the AER has allowed in Australia. We question how the AER can sustain its view that returns to distributors in Australia need to be almost twice as high as those in Britain? We think the implausibility of the AER's decision is made quite clear by evidence that Australian network service providers are borrowing money on off-shore capital markets at rates that are far below what the AER is requiring energy users to pay.
- **The ineffectiveness of an approach that the AER refers to as "detailed bottom-up reviews".** The AER's assessment centres on a review of "governance frameworks, processes and procedures". We are disturbed that the end point of the AER's review in most areas is little more than assertions that Energex and Ergon have governance frameworks, processes and procedures that accord with "good electricity industry practice". From this flimsy and opaque basis, the AER concludes that Ergon's and Energex's proposed expenditure increases of $2600m and $2000m respectively for the next regulatory period (real increases of 45% and 57% on the current period) will be efficient. Electricity users in Queensland should be provided with a more evidence based and transparent assessment than this, especially considering the extent of the price increases that would flow from the AER's draft determination.
- **The AER's failure to benchmark Ergon and Energex's expenditure as required under the Rules.** There is no evidence that the AER has made any attempt to benchmark Ergon or Energex's capex. This does not fulfill the AER's obligations under the National Electricity Rules (NER). On opex, the AER's benchmarking falls well short of the requirement to benchmark opex under the NER, because the AER has failed to benchmark Energex's and Ergon's proposed expenditure, and the AER has failed to define the benchmark against which Energex's and Ergon's expenditure is to be assessed. We have, however, defined such a benchmark and its shows that the AER's decision on opex means that Ergon and Energex will lag far behind the efficient frontier.

The submission also comments on the proposed Pass Through arrangements and the Service Performance Target Incentive Scheme (SPTIS). In relation to the former, it notes our serious concerns about the asymmetric nature of Pass Through arrangements in general, which will always provide cost increases that favour the distributor and are very unlikely to ever deliver any cost reductions. The AER needs to be mindful of this and ensure that any approved Pass Through events are strictly contained.

In the area of service targets, we think using historic average performance rewards historic under-performance. Targets should be set based on an upper-quartile benchmark, or if data for this is not available, based on trend lines that capture previous improvements in performance.

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1 Introduction and our interest in the AER's review

This is the Energy Users Association of Australia's (EUAA) submission to the Australian Energy Regulator on its draft decision of the price cap to apply to the two Queensland distribution businesses, Energex and Ergon, for the period 1 July 2010 to 30 June 2015.

The EUAA has around 100 members, many of whom are significant energy users in Queensland. They will be significantly impacted by the AER's draft decision to allow Energex to increase its prices by 67% over the regulatory period, and Ergon to increase its prices by 87%. These large increases are on top of significant price increases in other parts of the electricity industry value chain, as the industry adapts to emission reduction constraints and users bear the cost of the mandated promotion of renewable energy sources.

This submission is laid-out as follows:

- Section 2 explains the impact of the AER's draft decision on prices;
- Section 3 comments on the cost of capital;
- Section 4 comments on the AER's review of capex;
- Section 5 comments on the AER's review of opex;
- Section 6 comments on the AER's review of pass-throughs; and
- Section 7 comments on the AER's review of service standards.

2 The impact of the draft decision on prices

The AER's draft determination on Energex and Ergon Energy's revenue proposals results in a revenue increase of 64% for Energex and 87% for Ergon Energy over the regulatory period. We computed these increases based on the allowed revenues and AER's forecast of energy consumption[1] in the draft determination. The EUAA is extremely concerned about these increases, which come on top of 34% and 41% increases respectively during the current regulatory period. As a consequence, electricity distribution prices in Queensland will have risen by 120% for customers in Energex's network and 164% for those in Ergon's network over the ten years 2005-2015. This alone would have pushed their electricity charges up by 48% and 66% respectively.

This is an outcome that electricity users and the general economy in Queensland can ill afford, especially when (as the analysis in this submission shows), the costs that the AER appears willing to approve for Ergon and Energex are unnecessarily high and not efficient as required by the National Electricity Rules (NER). Nor would such an outcome meet the Electricity Market Objective in the National Electricity Law (NEL), which seeks to ensure that decisions made are *"in the long term interests of consumers of electricity",* including with respect to price.

The higher distribution prices resulting from the AER's draft decision would have adverse consequences on electricity users in Queensland. Their operating costs would increase, and they would have less capacity to sustain investment and jobs in the State. They would have to either pass on such cost increase to other industries and final consumers (if they can) or absorb them.

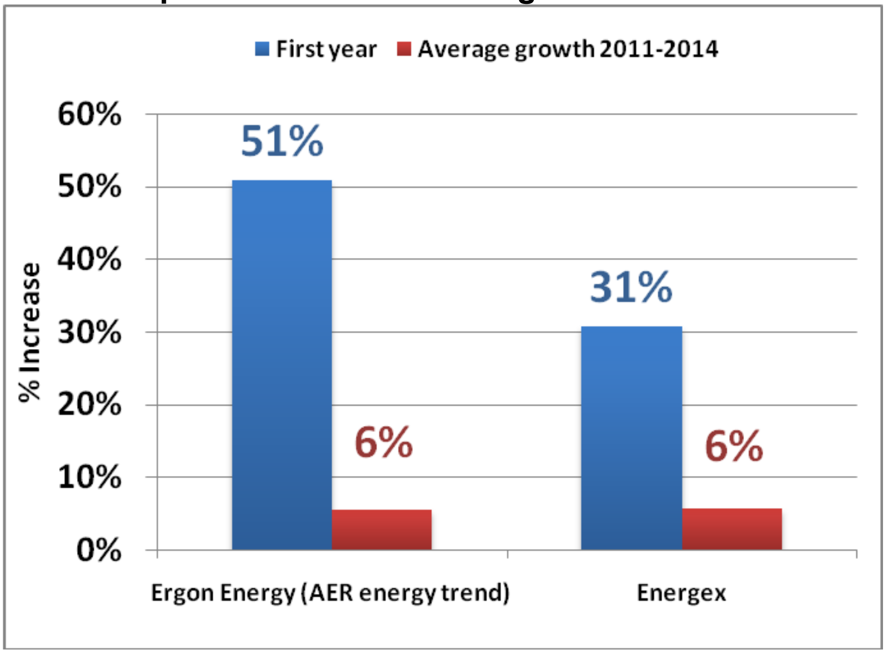
Industries in trade exposed sectors, such as mining, minerals processing and manufacturing, which are important in the Queensland economy, would be unlikely to be able to pass on the cost increases and their operations would be especially badly affected. Queensland businesses and households would also see impacts in terms of higher input prices and higher prices for many of the good and services they buy. As consumer and producer indices released following implementation of the AER's final determinations in New South Wales and Tasmania last year showed, the price impacts will also translate through into higher inflation. This was evident in the 2009 September quarter CPI figures where electricity prices were the largest single driver of the CPI increase both nationally, where they contributed to 21.7% of the 1.0 percentage point CPI increase, and in NSW and Tasmania, where they contributed 37% and 14% respectively, to those States CPI increases. Likewise, in the September quarter, the fastest growing component of producer prices was the electricity, gas and water component, which grew 12.1%.

The phasing of these increases over the regulatory period is also problematic for energy users. The AER's data shows increases of 31% and 51% for Energex and

[1] In the case of Ergon Energy, the AER rejected the proposed energy forecast but did not clearly state its own and therefore we used the AER's implied view on Ergon's forecast as presented by the dashed trend line as shown in figure 6.4 on page 79 of the draft determination.

Ergon Energy in the first year alone. We appreciate that the AER is simply following the Rules in its calculation of the distribution price increases over the regulatory period, but nonetheless wish to bring this to the AER's attention. These increases compared to the expected increases in the remainder of the regulatory period are show in Figure 1.

Figure 1: Annual price increases resulting from the Draft Determination



The severity of these distribution price increases must be considered in a broader context of rising prices in other parts of the electricity supply chain, including due to the expanded Renewable Energy Target and the impending Carbon Pollution Reduction Scheme (CPRS). These price pressures will progressively increase over the course of the regulatory period.

The EUAA's own calculations suggest that, together, these factors will result in a near doubling of average end user electricity costs across the National Electricity Market by 2015. The Business Council of Australia published a similar estimate in its 2009 infrastructure report prepared for them by Port Jackson Partners.[2] Their numbers show an increase of 95% in retail electricity prices between 2009 and 2015. This is a significant increase over such a short period. The AER needs to be sensitive to these cost pressures in considering its final decision.

2.1 Price impacts should be reported more clearly

As the AER applies a revenue cap regime in Queensland rather than a weighted average price cap one, such as in South Australia or Victoria, it is insufficient for the AER to only report X-factors for the business in its draft decision. These are only useful for understanding the revenue increase but need to be combined with the energy forecasts if prices are to be computed.

[2] "Seizing the opportunity to restore and reform Australia's economic infrastructure" – Rod Sims, October 2009. Part of the BCA "Groundwork for Growth"

The AER did not report prices changes resulting from its draft decision. By contrast the Queensland Competition Authority has done this. For example, in the QCA's final determination for the Queensland distribution businesses from April 2005, on pages 173 and 174 they set out the aggregate annual revenues requirements (AARR), forecast consumption, implied nominal price (c/kWh), the annual percentage change in the nominal price, the implied real price, and its annual percentage change.

In the case of the Queensland businesses, it is unhelpful for the AER to only report the percentage increases in revenues and then to attempt to calculate the impact on an average residential users total electricity bill, as they did in this case. We could not find anywhere in the Draft Determination where the changes in distribution prices were reported. This lack of transparency is a concern to energy users.

Additionally, if the AER is going to report retail price impacts, it would be helpful if it is stated clearly how it has then translated this into average tariff changes. The AER calculated average price changes of 26.5% and 26.9% (nominal) for end users in Energex's territory and Ergon's territory respectively, but has not specified how it has calculated this. We have not been able to replicate the AER's calculation of price impacts. We question if the AER's claim of the price impact to end users of "just" 26.5% and 26.9% can be sustained in light of the price increases to Energex and Ergon of 64% and 87% respectively.

Similarly, with respect to residential customers, the AER calculated State average price increases of 18% over the regulatory period. It is not clear what assumptions underlie this calculation. And again, for the reasons described above we question the AER's calculations.

A clear calculation of the impact of its decisions on end users is essential for effective consultation. We call on the AER to pay greater attention to this in its final decision for Energex and Ergon, and do also do so in forthcoming price control reviews of other network service providers. Given that the AER's Chair has written to the CEO's of both Energex and Ergon and sought their co-operation in providing better and more timely notification of likely price increases to end users, it would be helpful if the AER also provided more accurate, extensive and relevant analysis of the price impacts of its draft and final determinations.

2.2 Early notification of tariff increases is still important

Many of the EUAA's members in Queensland and in other states are commercial and industrial users who have market-based retail contracts where the distribution component is treated separately as a pass-through. These tariffs typically have several components such as a monthly peak demand kVA component, as well as the kWh energy based components. These users need to understand how the AER's draft decision impacts each of the relevant components of the tariffs. Only the distributors, Energex and Ergon Energy, are capable of providing this information.

In view of the very large first year price increases, early notice is essential to allow users to incorporate the information into their often lengthy budgeting cycle. Across the NEM this has not been handled well. Energy users in NSW, after the AER's

2009 final determination for distribution and transmission, were notified of price increases as high as 55% only two weeks before the start of the 2009-10 financial year.

We welcome that in response to concerns that energy users have raised in submissions and in public forums, the Chairman of the AER has written to the Queensland distributors specifically urging them to provide sufficient notice of and earlier information on proposed tariff changes. We have received indications from Ergon Energy and Energex that they are in the process of writing to their larger customer to provide indicative tariff information based on both the AER's draft determination and their revised proposals and will likely be finished with this process by early to mid March. Our members are keen to obtain indicative price increases at the earliest opportunity and we encourage the AER to continue to ensure that the distributors engage with energy users in a way and within a time frame that meets the needs of customers to have useful information as early as possible, even if that information cannot be totally accurate.

3 Comment on cost of capital

In its draft decision, the AER has determined allowed rates of return on a similar basis to its Final Decision for the NSW distributors.

The EUAA disagrees with the AER's decision on its cost of capital. In our submission to the AER's WACC review we set out our disagreement on this, and noted that the AER's Board had set a level of WACC that was higher even than the top end of the range recommended to it by the staff of the AER and the AER's consultants.

In their recent paper Mountain and Littlechild,[3] compared the cost of capital allowed by the AER, for distributors in Australia, with the cost of capital allowed by Ofgem in the UK. They noted that:

> "*Most of the difference is explained by differences in the assumed cost of equity and debt. Ofgem assumed the cost of equity was 6.7% (real), while the AER used 9.3% (real). Much of the difference here is attributable to the AER's much higher equity beta (1.0) compared to Ofgem's (0.24 to 0.34). With respect to the cost of debt, Ofgem used a value of 3.6% (real) based on trailing yields on A and BBB-rated bonds. The AER used a value of 6.3% (real) based on a margin on top of the risk free rate, nearly twice as high as Ofgem's assumption."*

We have noted that in response to the Littlechild and Mountain paper, the Chairman of the AER has made a number of public statements on the cost of capital. Specifically, he suggested in the *Business Spectator*[4] that the difference was accounted for by lower guilt rates in the UK than Australia, cross country differences meaning higher market risk premiums in Australia and that Ofgem's allowed rates of return were "perhaps" too low.

With respect to the first point, Energex and Ergon, like other Australian distributors, are not funded through Commonwealth government guilts. So the relevant comparison of debt costs in Australia to those in the UK is between the cost of debt for corporate debt raised by distributors in Australia with those in the UK. On this measure, we suggest there is no obvious reason to believe that over the long term there should be a sustained difference in the real cost of corporate debt between the UK and Australia.

In addition, we draw the AER's attention to the fact even if there are, from time to time, differences in the cost of corporate debt in Australia compared to that in the UK, Australian distributors should be expected to meet the majority of their debt

[3] Mountain, B. R., & Littlechild, S. C. (2009 December). "Comparing electricity distribution network costs and revenues in New South Wales and Great Britain", Series Paper, Electricity Policy Research Group, Faculty of Economics/Judge Institute of Management, University of Cambridge.

[4] http://www.businessspectator.com.au/bs.nsf/Conversations/Regulation-T55PM?OpenDocument&src=srch

capital requirement from the cheapest sources available including through international bond markets, rather than just Australian bond markets, if the latter are more expensive. As such the relevant consideration is the cost of debt for Australian utilities in international capital markets, not just Australian capital markets. There is, of course, nothing unusual about this, as the bulk of debt raised by Australia's major corporations is sourced from off shore capital markets.

In this regard, we note a recent capital raising by SP Ausnet (SPN) in Victoria for corporate debt in off shore capital markets. In a recent research note, Credit Suisse said that:

> *"We have seen a number of the Australian regulated utilities accessing attractive off shore bond issuances over the past six months, which are providing tenure longer than available in the Australian bank debt market, and more favorable rates. The Australian Energy Regulator (AER) in its draft decision for ETSA utilities proposed a debt margin of 429bps. This represents a ~280bps wind fall gain to where SPN is currently able to issue debt."*[5]

A small part of this difference – probably around 50 basis points – may be accounted for by SPN's A- credit rating (compared to the BBB+ used in the AER's WACC methodology). However, the largest parts of this difference is explained by the fact that debt capital is currently cheaper to access in off-shore capital markets. By setting a cost of debt in Australia based on the AER's theoretical construction of a debt premium on top of *Australian* risk-free rates, the AER is allowing a cost of debt that is evidently completely out of proportion to the price that companies are actually paying. This is a critically important issue. End users are paying for the windfall noted by Credit Suisse. This must be corrected in the Final Decision.

On the cross-country differences in market risk premia, the AER should produce evidence that the values of the equity beta that it has used (0.8) can be justified in comparison to the much lower values in the UK (0.2), in order to substantiate the AER Chair's comments.

On the AER Chair's suggestion that allowed rates of return are "perhaps" too low in the UK, it would be helpful if the AER justified this assertion having regard to the fact that all the distributors in Britain accepted Ofgem's proposals. If they had thought the rate was too low they had an opportunity to refer Ofgem's proposals to the Competition Commission. But the businesses chose not to. To the contrary, they quickly accepted Ofgem's proposals. Since the AER believes that Ofgem has "perhaps" made the wrong decision, the AER should explain why the British distributors accepted Ofgem's proposals.

The Chairman of the AER also recently opined on the cost of capital in a letter to the Australian Financial Review on 18 February 2009. In that letter, he asserted that *"simply applying UK rates of return to Australian businesses would mean the rates set would be too low"* and that this *"would lead to less investment and a diminution of service quality and reliability".*

[5] Research note on SP Ausnet, Credit Suisse, Sydney, 19 February 2010.

The evidence provided by Credit Suisse contradicts this. Lenders in British capital markets have been happy to invest in Australian utilities at rates that are 280 basis points below the levels that the AER allows the businesses. If the AER has evidence to support its Chairman's statement, we call on the AER to provide such evidence in its final decision. However, in the absence of such evidence, we call on the AER to adjust its allowance for the cost of debt to the levels that Australian utilities are paying. In this regard, the approach adopted by Ofgem of trailing yields on appropriately-rated corporate debt appears to be an appropriate measure for the AER to also use.

4 Comments on AER's review of capex

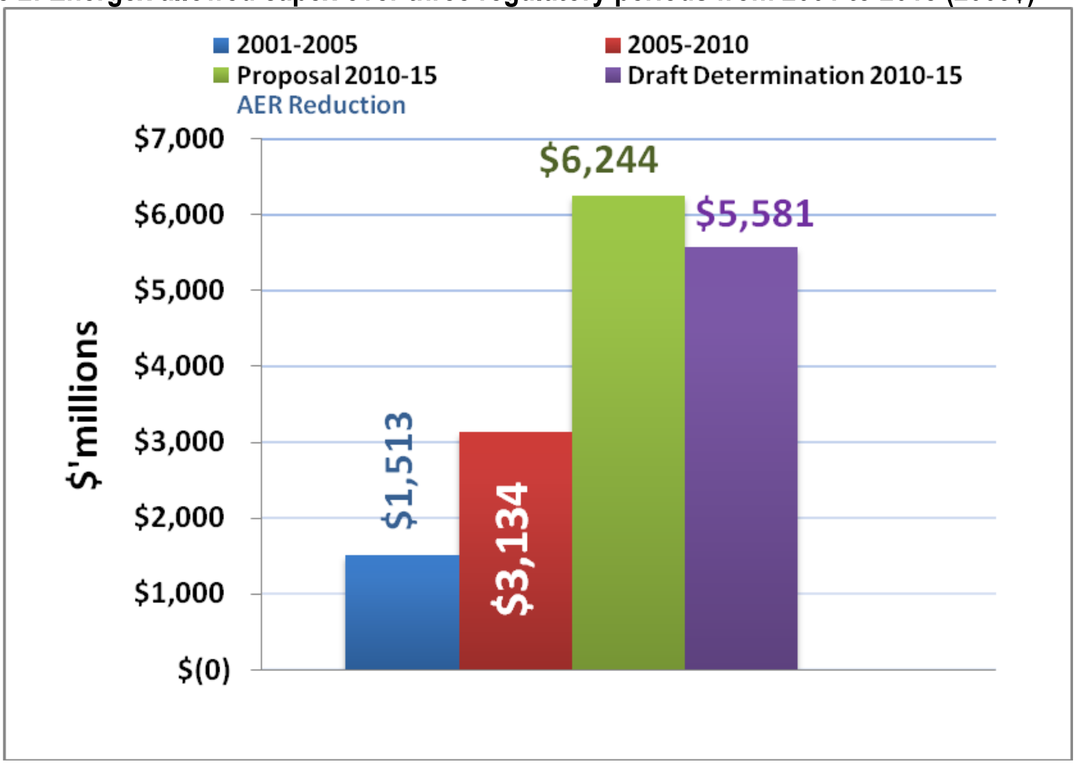
4.1 Summary of the AER's decision

This section assesses the AER's draft determination in terms of Energex and Ergon Energy's capex allowances. It starts by comparing the distributors' proposals and draft decision with the allowances for the previous and current periods, that is, the 2001-2005, and 2005-2010 periods respectively.

Energex

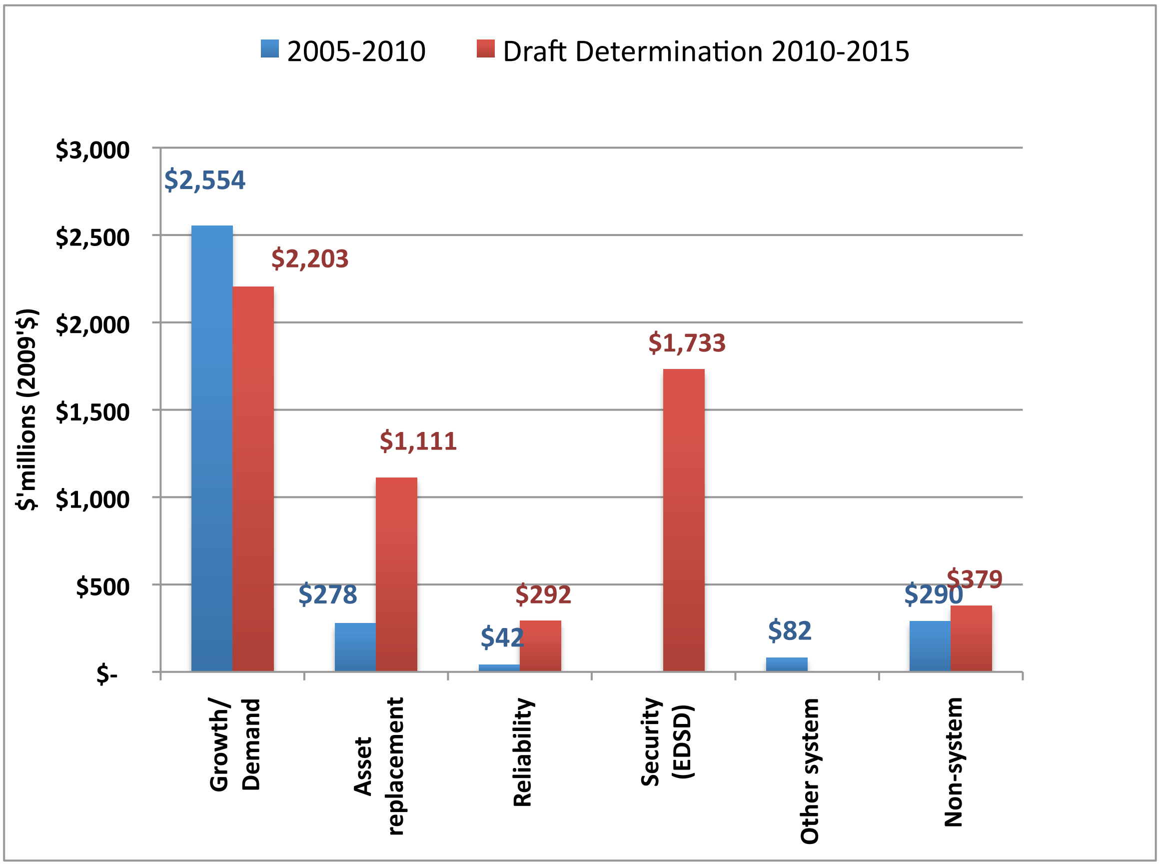
In their draft determination, the AER applied a real reduction of 10.6% to Energex's proposed capex, from the $6244m proposed to $5,581m (2009 dollars). Figure 2 shows that this is still a very substantial real increase of 78% on their current period allowances. This increase comes on top of a 107% increase in the current regulatory period.

Figure 2: Energex allowed capex over three regulatory periods from 2001 to 2015 (2009$)



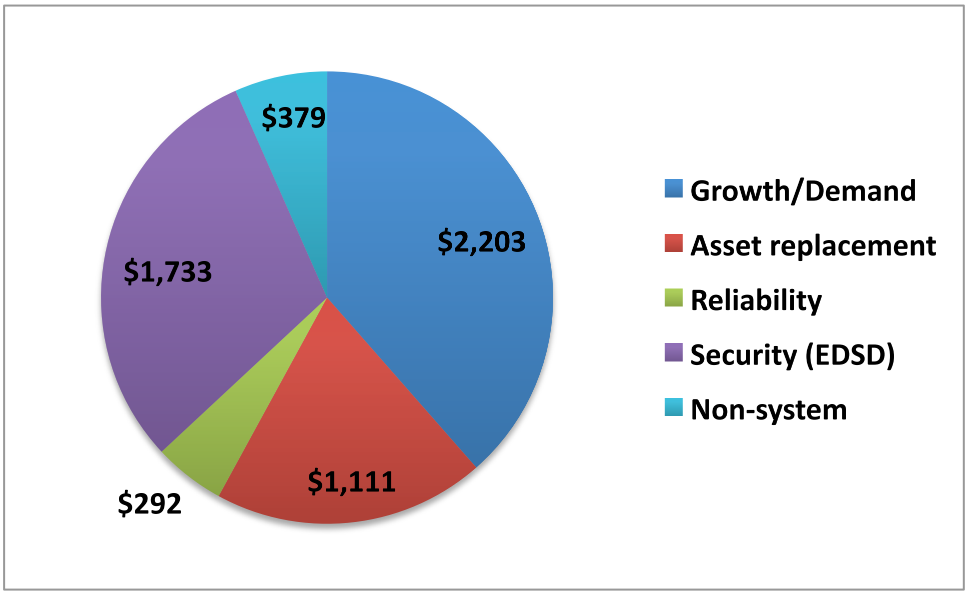
We have broken the allowed capex down into its major components and compared them with the current period allowance. This is set out in Figure 3 which shows that the demand growth component remaining at its historical high, increases in the asset replacement component, and the new "Security" component (attributable to the 2004 Sommerville review). This component ($1.8bn) is nearly a third of the total capex allowance and makes up 70% of the increase in capex over the next regulatory period.

Figure 3: Change in major components of Energex capex from the current to next period



It is also instructive to review the components in terms of their relative contributions to the total allowance as can be seen from the pie chart in Figure 4. In addition to the prominence of the EDSD component (the second largest), the chart shows that the largest component is the demand growth component, while the third largest is asset replacement. The magnitude and rate of growth in the latter is particularly surprising for a network as young as Energex's.

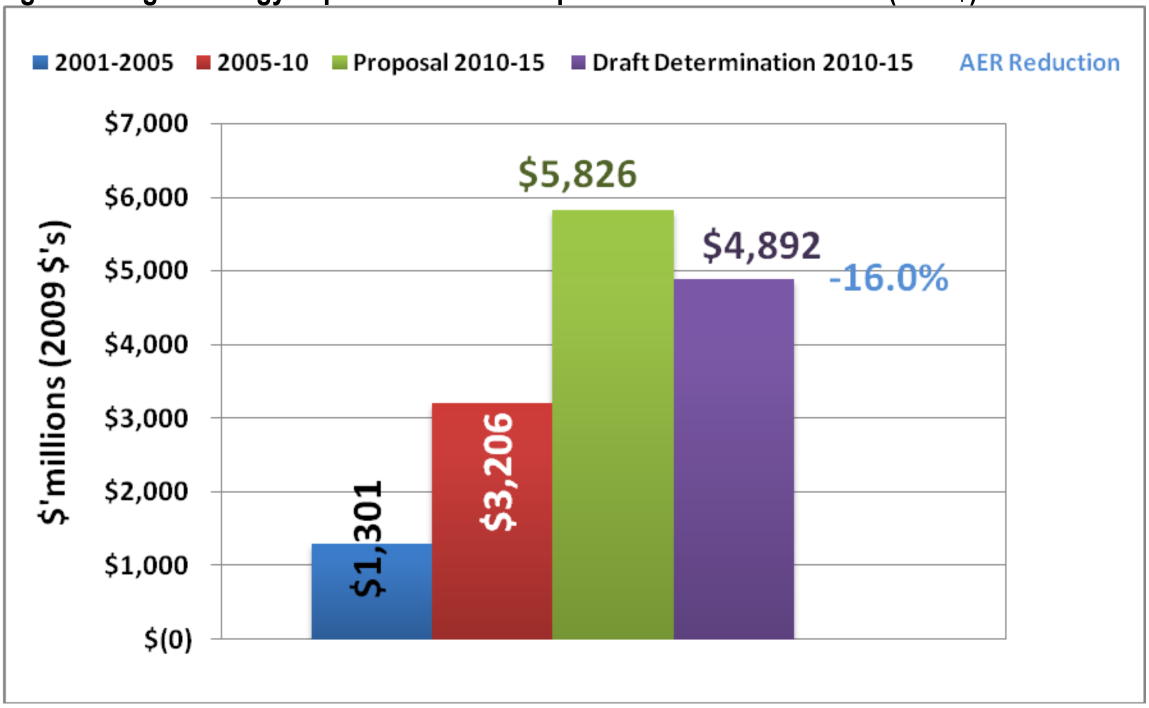
Figure 4: Energex capex breakdown by major components based on AER's draft decision ($'2009)



Ergon Energy

Figure 5 shows that Ergon Energy's capex follows a similar pattern to Energex of increases over the three periods. The AER's draft decision has reduced Ergon Energy's capex by 16%, mainly because the AER suggests that network peak demand will not grow as rapidly as Ergon expects. The AER's draft decision allowance at $4.9bn is around a 50% increase in the allowance for the previous period, which was in turn around 150% higher than the capex allowance in the 2001-2005 period.

Figure 5: Ergon Energy capex over the three periods from 2001 to 2015 (2009$)



In order to understand the capex better, we broke down the changes to their categories as we did in Energex's case and set the results out in Figure 6. This shows a large increase in the asset replacement category and an even large increase in the demand growth categories.

Figure 6: Change in major components of Ergon's capex from the current to next period (2009$)

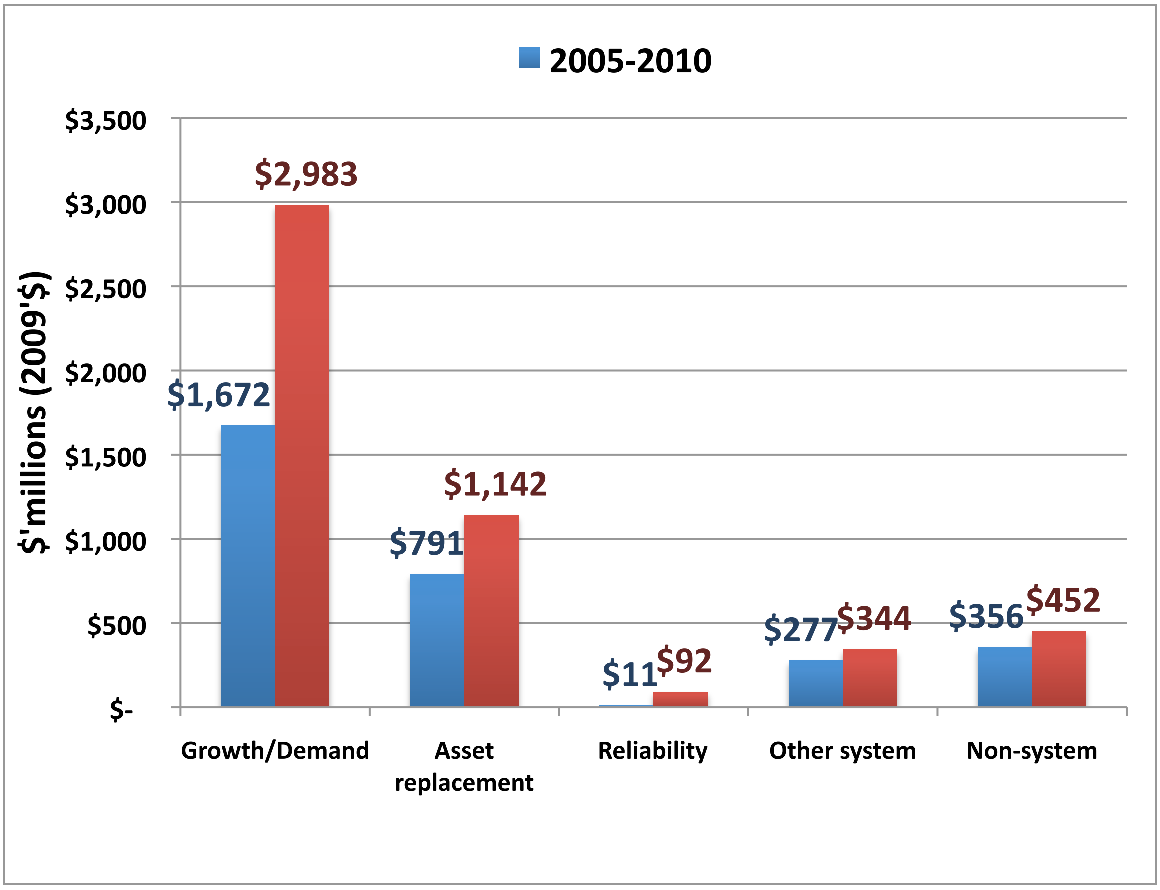
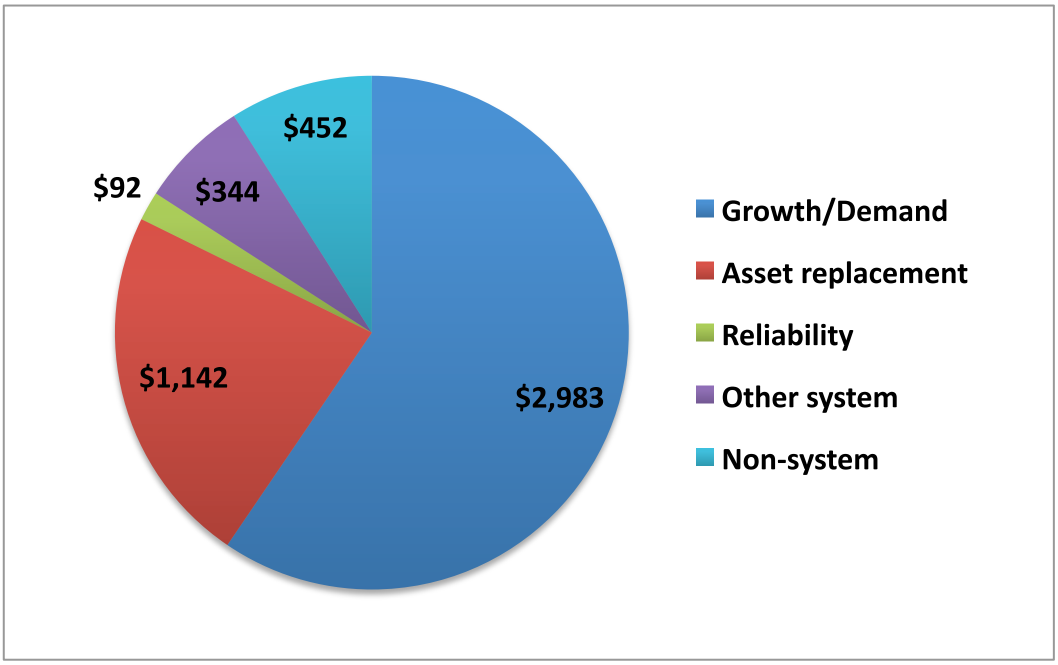


Figure 7 shows that the demand growth category is by far the largest at around 60% with the second and third largest category being asset replacement and non-system capex respectively.

Figure 7: Ergon capex breakdown by major components based on AER's draft decision (2009$)



4.2 Misplaced reliance on processes and governance frameworks

We are concerned that the AER has not produced a sufficiently robust and transparent assessment of Ergon and Energex's capital expenditure proposals.

Distribution businesses in Australia are large, complex, capital intensive corporate entities. They employ numerous specialist managerial and professional staff. These staff have developed functional and sectoral expertise in procuring and operating assets, over a number years. The AER regulates their core business and naturally they will expend substantial resources on ensuring an outcome favourable towards them – which resources we note are funded out of opex, which is in turn funded out of distribution charges paid by Queensland electricity users.

By contrast the regulator is at a disadvantage. They have fewer resources, are not experienced in operating a distribution business and rely on information provided by the regulated business. They also have a limited time, less than 12 months, in which to complete their review.

The core of the AER's approach is what it often refers to as a detailed bottom-up review. Faced with a substantial information asymmetry, constrained review periods, and the AER's resource constraints, it is therefore inevitable that "bottom-up" reviews becomes *"arbitrary and ad hoc"*[6] as the learned regulatory economist, Professor Paul Joskow has put it.

We acknowledge that the AER, its staff and consultants have been set a difficult task. Regulatory incentives are intended to encourage efficient expenditure. However, the revenue cap regulation also provides strong incentives for the businesses to overstate their claim, and the regulated firms will expend considerable resources and energy trying to convince the regulator of the merits of its claim. An effective regulator must make use of tools that allow it overcome information and resource asymmetries.

The Rules list ten factors to which the AER is required to have regard in determining expenditure allowances. We suggest that the most effective of these in setting expenditure allowances as required under the Rules (i.e. expenditure must be efficient and in the long term interest of users) – and the one that the AER has so far largely not implemented – is benchmarking.

In the Energex and Ergon reviews, the AER has not benchmarked capex as provided for under the Rules (and in a manner that would accord with good regulatory practice). Rather, in attempting to implement its "bottom-up" approach the AER has turned its focus instead to the "governance frameworks", "processes" and "procedures" of the two Queensland distributors.

[6] Joskow, P. (2007),. Regulation of Natural Monopolies. In A. M. Shavell (Ed.), *Handbook of Law and Economics.* (pp. 101-102)

Typically such frameworks, processes and procedures are deemed to result in efficient expenditure if they accord with what the AER (and its consultants) consider to be "good electricity industry practice". For example[7]:

- One of the first items that the AER notes in its approach to assessing capex (page 84) is that:

  "*due to the limitations of reviewing a large number of projects in detail, relatively more reliance has been placed on a review of the Qld DNSPs policies and procedures and the underlying assumptions …"*

- PB Associates, the AER's consultants, also stressed the importance of "*planning and governance policies and procedures as a critical element of assessing the prudence and efficiency of the capex*" in its assessment of proposed expenditures. In its conclusions on system capex, the AER reports (on page 93) that the first reason PB gives to justify its decisions is that "*Energex's capital governance framework is consistent with good electricity industry practice and is likely to lead to prudent investment decisions.*"

- PB Associates typically reduced its assessment to whether or not it considered Ergon's and Energex's procedures and processes were in accordance with "good electricity industry practice," For example, also on page 94, the AER notes that PB had concluded that "*Ergon Energy's capital governance framework accords with the principles of good electricity industry practice in general, although the framework is still to be fully implemented".* PB continued to refer to this *"good electricity industry practice"* repeatedly in cases as evidenced on pages 98, 99, 105 and elsewhere.

- With respect to Energex, on page 95, the AER reaches the conclusion that *"Having considered Energex's capex planning and governance framework, and advice from PB, the AER is satisfied that Energex's policies and procedures for capex planning and governance demonstrate … assurance and good practice such that their application is likely to lead to prudent and efficient investment decisions."*

The term "good electricity industry practice" may have some useful meaning as a description engineers might use to describe a network that is maintained to specific standard, or a transformer that is installed and operated in a particular way to ensure its reliability and safety. But what does "good electricity industry practice" mean in the lexicon of regulatory economics, and specifically the AER's obligations under the National Electricity Rules?

Why is it reasonable to conclude that "good electricity industry practice" is synonymous with efficient expenditure? If efficiency was so easy to determine, there would be little need for the considerable effort that policy makers in Australia and internationally put into the design of regulatory regimes and regulatory incentives. For this reason, we suggest that the AER's approach of defining "efficient" as synonymous with "good electricity industry practice" has no sound basis in the theory or application of regulatory economics. If the AER considers that this is wrong, we

[7] Note that all page references in these dot points are to the AER's draft decision

call on the AER to justify its approach with reference to the established regulatory economics literature.

Furthermore, as a practical matter, taking account of the time allowed for a review, and the AER's significant resource constraints, how can the AER feel that it has the resources or skill needed to reach conclusions on the "governance frameworks", and a wide variety of the processes and procedures of these large and complex businesses?

These are fundamentally important questions of regulatory approach, and we ask that the AER clarify this in its final determination.

We also suggest that much greater use of benchmarking (as we discuss further in Section 4.4) is a far more suitable approach and we encourage the AER to turn its attention to this for the Final Determination on Energex and Ergon.

4.3 Specific capex assessment issues

4.3.1 Unit costs and escalation rates

One of the key components in the preparation of a capital expenditure program is to cost the key components of the electricity networks such as transformers or poles. In the case of both Ergon and Energex, the AER's consultant, PB did not itself assess the DNSP's unit costs. As the AER states on page 98:

> *"The AER engaged PB to provide an independent view on the prudence and efficiency of Qld DNSPs' capex proposals. While not required to provide a comprehensive benchmarking review of unit costs, PB was required, as part of developing its view on the efficiency of investment decisions, to undertake a review of unit costs where it considered this was necessary."*

However, PB's best effort at assessing Ergon Energy's unit cost assessment was to merely review their processes and procedures, and to note the results of unit costs reviews conducted by Ergon's own consultants, SKM. In particular, quoted PB as stating (page 99) that it had:

> *"… reviewed Ergon Energy's processes and procedures for cost estimation, including the development of unit costs for Ergon Energy's 'specified work' and the range of methods used to develop costs for Ergon Energy's 'unspecified work'. PB noted that an independent review by SKM found that Ergon Energy's unit costs were within a nominated tolerance range of +/– 15 per cent and that SKM concluded the unit rates were 'reasonable and efficient cost estimates for the assets'. Based on its review, PB concluded that the processes and procedures Ergon Energy uses in relation to cost estimation reflect good electricity industry practice."*

The AER also relied on the advice of Ergon's own consultants (page 100):

> *"The AER notes that 85 per cent of Ergon Energy's proposed capex is based on unit costs independently reviewed by SKM. The AER notes SKM's conclusion that Ergon Energy's unit cost estimates are reasonable and efficient. The AER*

also notes PB's conclusion that the processes and procedures Ergon Energy uses in relation to cost estimation reflect good electricity industry practice."

Similarly, in assessing Energex's unit costs, the AER described the approach taken by PB thus:

> *"PB reviewed the estimating computer program used by Energex to develop cost estimates for its capex program…. PB found a consistent approach had been applied to the reviewed project,…. Based on its review, PB concluded that the processes and procedures Energex has used to estimate costs in developing its capex forecasts reflect good electricity industry practice and that their implementation should lead to a prudent and efficient outcome."*

No sign of an independent review could be found in the draft determination or in PB's own conclusions. Furthermore, it is of a concern to users that PB's terms of reference specifically excluded benchmarking of unit costs, as PB states on page 5 of their Energex and Ergon Energy reports:

> *"PB's review of ENERGEX (Ergon Energy's) forecast capex allowance has specifically excluded the following matters from our scope of work:*
>
> - *benchmarking of unit costs*
> - *the level of forecast demand."*

The EUAA considers that this is not an independent, robust and transparent way to review capex, especially given the large programs that the AER is proposing to approve. Unit costs have a significant impact on the size of the expenditure allowance. It is simply inadequate that the AER relied on PB's views of "processes and procedures" and Ergon's own consultant's views on this matter. The AER should have assessed this itself, and this assessment should have included some form of rigorous comparison of Energex's and Ergon's unit costs with those of its peers.

4.3.2 Non-Network Capex

Non-network capex, while somewhat smaller than the other areas of capex, is still significant. We support the AER's refusal to recognize Ergon Energy's $188m claim for corporate property. However, we have several remaining concerns. We point specifically to Ergon Energy's UbiNet project (there was no statement of the cost of this project in the AER's documentation).

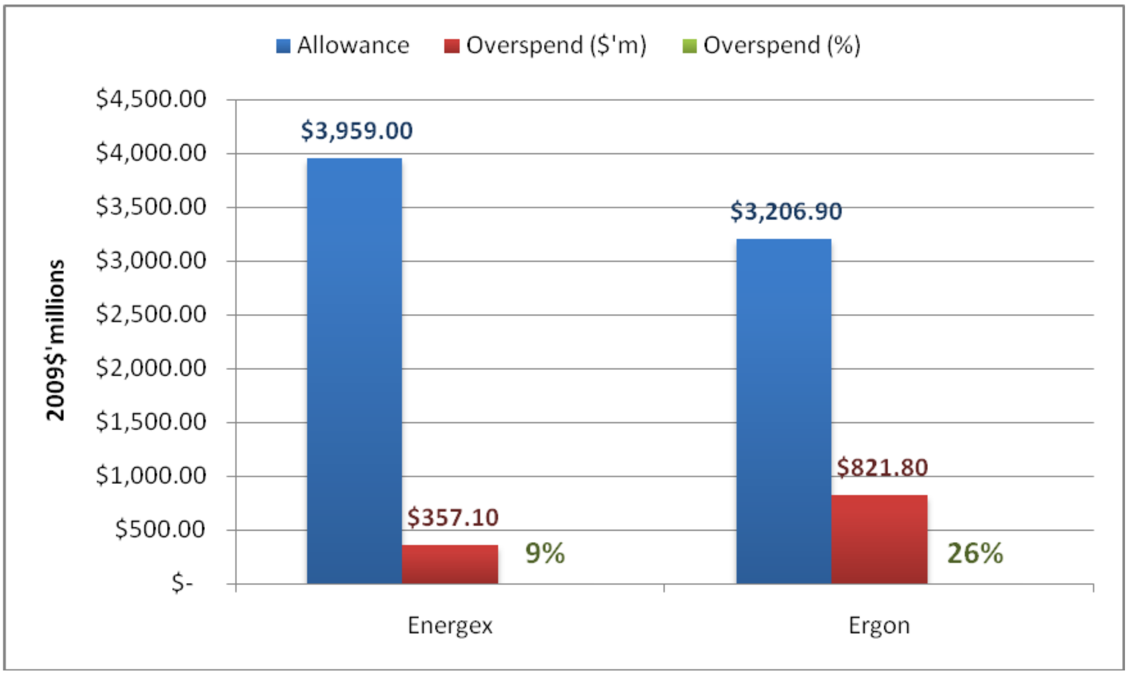
Cost-benefit assessments of the Ubinet project by the Queensland Treasury Corporation and Evans and Peck concluded there was no net benefit. PB did not present any evidence to the contrary but concluded that the project was economically beneficial. The AER relied on this assertion to include this expenditure in the allowance. We disagree with this. This is a speculative, risky investment and Ergon's shareholders, not users, should bear the risk.

Furthermore, it is unacceptable that the costs of this project are not available. We raised this issue in our submissions on Energex and ETSA's proposals, but the AER has not responded to this matter.

4.3.3 Comment on the AER's review of capex overspend

Both Energex and Ergon, are forecasting significant overspend of their current capex and opex allowances as can be observed in **Figure 8**

Figure 8: Capex overspend forecast for the current period 2005-2010



These overspend calculations are based on table 7.1, p. 85. in the draft determination which sets out the current period capex outcomes. The AER and PB stated that they believe these overspends have been prudent based on consideration of various factors, the most notable of which are the EDSD compliance, unexpected demand growth, or changes in capitalization policy. These are rather vague explanations when discussing a total overspend of nearly $1.2B or around 16% of the total allowed by the QCA.

We remain concerned that the AER has not justified why energy users should bear the overspend when some of the major cost drivers they quote, specifically EDSD compliance and demand growth related to large customers in the Ergon Energy area, were key issues of concern to the QCA in their decision for the 2005-2010 period and an additional capex allowance was set aside as part of a special pass through mechanism. We draw the AER's attention to the following sections from that decision relating to this pass-through mechanism for additional capital expenditure allowed to Energex and Ergon by the QCA , on page (iii) of their decision:

> *"During the next regulatory period, Energex is forecast to spend $2.71 billion on capital. If necessary, this amount could increase during the regulatory period to $3.43 billion. Ergon is forecast to spend $2.77 billion on its general network and has a further $400 million available to meet the needs of certain*

large customer-related projects. In addition, Ergon's general capex requirement could be increased by a further $47 million during the period, depending on the circumstances, taking its total capital expenditure to a possible $3.22 billion."

And on page (xii) regarding Energex:

"The Authority is concerned that there is still considerable uncertainty surrounding the forecasts of capex. The amounts of capex being forecast by BRW and the distributors are unprecedented. The Government's response to the EDSD Review has placed new and unfamiliar obligations on both distributors. The difference between what is forecast by BRW as being required by Energex and that which Energex still believes may be needed is significant. To ensure that customers do not suffer a shortfall in service quality due to a lack of sufficient financial capacity, the Authority has included a pass-through mechanism which will apply to the gap between the amount BRW considered Energex required for capex ($2,707 million) and that which Energex proposed ($3,427 million).

If Energex is able to establish to the Authority's satisfaction that it needs to spend more in total on capex than BRW has assessed as necessary and that it could undertake this expenditure in an efficient and properly planned manner, the Authority will consider re-opening that aspect of its Determination"

These amounts to a very significant pass-through amount which of around $860m in 2010 dollars.

In the case of Ergon energy, the QCA allowed a similar pass-through and we note the following important comment on page (xiii):

"As suggested by the EDSD Review, endorsed by BRW and supported by Ergon, the Authority has removed from Ergon's capital expenditure building block an amount of $400 million, representing the estimated costs associated with a number of large capital expenditure projects. These are projects that Ergon has identified as having a value greater than $5 million; are associated with meeting the needs of single large customers; but are less than 80 per cent certain in their timing."

And the QCA concludes on page (xiv):

"Accordingly, $2,769 million will be incorporated into Ergon's capital expenditure building block and a further $400 million will be set aside for the time being. In the interests of equity, the Authority has also decided to extend the capex pass-through provision discussed above for Energex, to Ergon."

This pass-through amounts to around $540m in 2010 dollars.

Based on our calculations, the $3,959m and $3,207m allowances for Energex and Ergon Energy respectively, reported by the AER and attributed to the QCA are of similar magnitude to the pass-through inclusive allowance from the QCA, which would be $4,112m and $3,860m for the two businesses respectively by our calculation. It is not clear to us how the figures reported by the AER were arrived at; and this needs to be explained properly by the AER,

Total pass-throughs of $1.4bn ($2010) are significant and we believe the AER needs to explain where the overspend was incurred. It is unacceptable that the AER has dealt with this substantial issue without providing an adequate explanation.

The issue at hand is that the AER needs to protect users from inefficient overspend. To do this the AER needs to establish the following:

- Did Energex and Ergon call upon the QCA additional capex pass-through mechanism and to what amount?
- In particular, the following should be explained:
- Did Energex utilise the $860m for EDSD and related purposes and to what extent?
- Which, if any of the possible large customer loads expected by Ergon Energy came on stream and how much did these cost to connect. Which did not eventuate?
- How were the costs of Ergon Energy's large customer connections sequestered from other Ergon Energy customers?
- How do the overspends reported by the AER, totaling $1.2 billion, relate to the QCA pass-through and what are the sources of any numerical discrepancies?
- Were the expenditures, both within, and outside the QCA's pass-through mechanism incurred efficiently?

4.4 Failure to benchmark

In the draft determination, the AER has failed to benchmark capex as it is required to under the Rules. In the draft decision we could not find any evidence that either the AER or its consultants had even attempted to benchmark Energex or Ergon's capex. The Rules require the AER to have regard to Energex and Ergon's capex against the capex of an efficient DNSP. The EUAA raised this issue, as one of critical concern to users, in its submissions on Energex and Ergon's expenditure proposals.

The AER has no discretion to decide which of its requirements under the Rules it will choose to implement and which it will not. The Rules have the force of law, and the AER must carry out its legal obligations for the Final Determination.

5 Comments on AER's review of opex

5.1 Summary of AER's decision

This section outlines the opex impacts of the AER draft determination. As in our capex analysis, we present the outcomes of the period 2001-2005, current period (2005-2010) and the coming period. Figure 9 and Figure 10 describe the trend in Energex and Ergon Energy's opex expenditures. These figures show a significant increase across the three periods. In their proposals, Ergon Energy and Energex both asked for nearly $2bn in operating expenditures.

The AER has applied a revision downwards of 8% real to Energex's opex and a more substantial reduction of nearly 20% to Ergon Energy.

The allowances result in a 12% real increase for Energex. But this follows an 82% real increase on the amount that the QCA allowed in the current period, compared to the 2001-2005 period.

In Ergon Energy's case the 25% increase over the current period follows a 30% increase allowed by the QCA for the current period, compared to the previous period.

When compounded these increases amount to a doubling of Energex's opex in real terms, between 2000 and 2010, and a 60% real increase for Ergon Energy over the same period.

Figure 9. Energex approved opex over the previous, current with next period proposed and AER decision

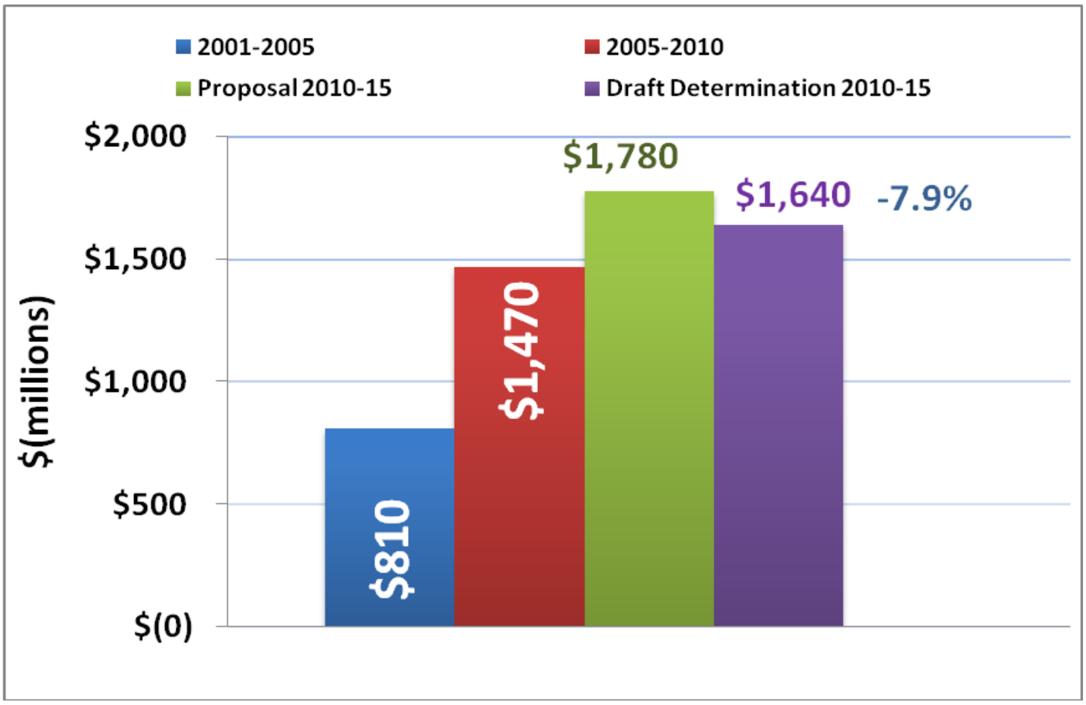
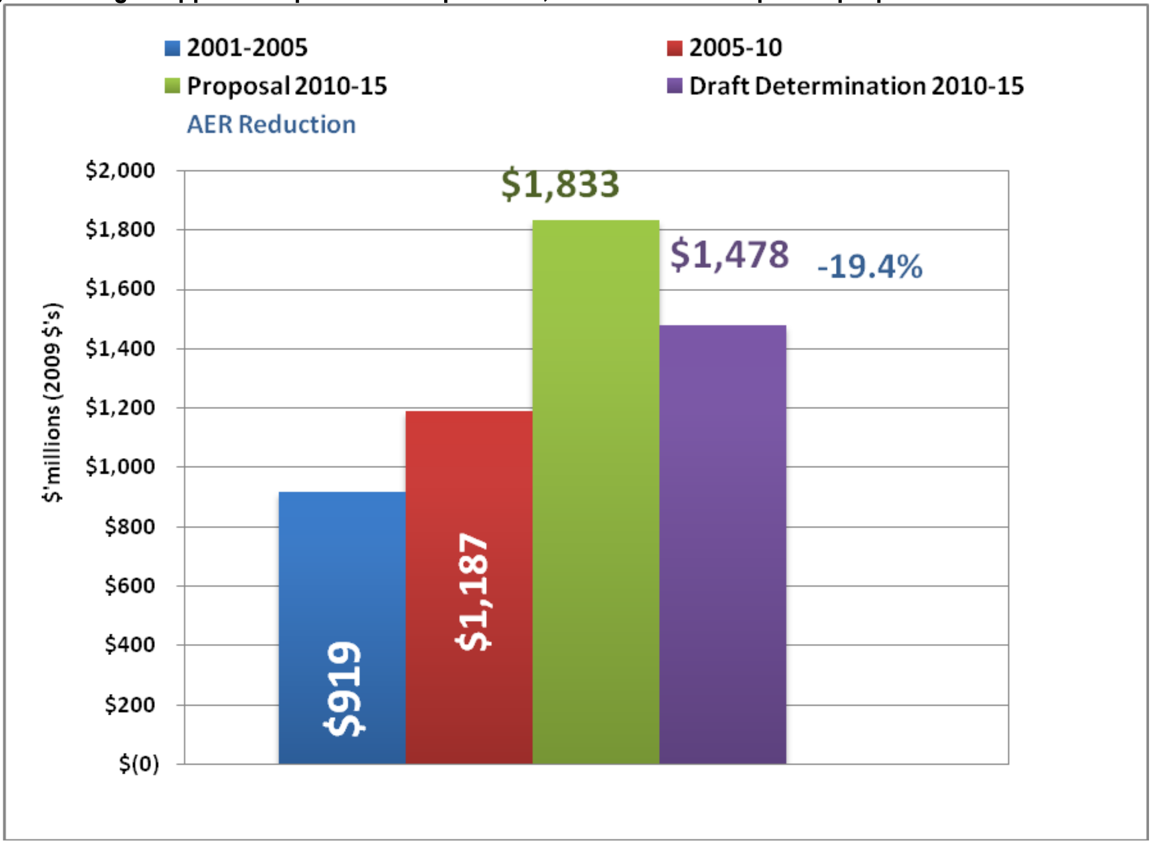


Figure 10. Ergon approved opex over the previous, current with next period proposed and AER decision



5.2 Misplaced reliance on processes and governance frameworks

Section 4.2 set out concerns about the AER's misplaced reliance on an assessment of process and governance procedures in assessing capex. This same concern applies also to opex, although perhaps to a lesser extent in view of the approach of establishing opex through a base year and then variations on top of that base year. Nevertheless, we noted several instances where the AER has ultimately relied on reviews of processes and governance procedures. For example:

- On page 132 in describing its overall approach to opex assessment, the AER says that in determining whether the opex reflects the requirements of the NER (i.e. is prudent and efficient), the AER has examined whether "*the governance frameworks, asset maintenance strategies and systems, operating procedures and practices are likely to result in forecast expenditures … consistent with the opex objectives*"

- On page 133, the AER notes that it has *" … placed less reliance on the review of individual expenditure programs and project reviews"* but instead *"has reviewed the policies, procedures and underlying assumptions, and how these have been applied by the Qld DNSPs, historically, and in developing the forecasts."*

- On page 145, the AER paraphrases PB's assessment of Energex's controllable opex to be prudent and efficient, noting that PB's *"key findings"* were that "*Energex's asset management principles, processes and procedures are prudent and efficient … ",* that *"Energex's key policy documentation and policies were prudent",* and that *"Energex's bottom up forecasting methodology was sound and was likely to result in accurate forecasts."*

Again, for the reasons set out in Section 4.2, we think it is simply not credible for the AER to rely on what it thinks about Ergon and Energex's governance frameworks and procedures to support a judgment on the efficiency of proposed operating expenditures.

Given the size of the proposed opex, the size of the increases compared to the current period and the large increases in distribution prices, electricity users require a more robust and transparent assessment by the AER under all ten opex factors listed in the Rules including benchmarking.

5.3 Misplaced reliance on revealed costs in establishing starting point

The AER's approach to establishing Ergon and Energex's opex allowance is to set the starting point as the operating expenditure in 2007/8. Variations on this starting point then set the allowed expenditure during the regulatory period. This approach relies on the idea that the "revealed expenditure", i.e. the expenditure that the business incurred in some previous year is, by definition, efficient expenditure. The underlying assumption is that businesses have incentives to reduce operating expenditure to its efficient level.

The AER might argue that its approach is more than this since it has calibrated its assessment of the efficient starting point, by benchmarking the opex. But, as we discuss in the next section, we do not think that the AER has done this according to what the Rules say.

More generally, we are concerned that the regulatory arrangements and the regulatory cost accounts are not sufficiently well developed to place any reliance on the level of operating expenditure as representative of efficient expenditure. In the absence of a consistent definition of what constitutes operating and capital expenditure, the regulated businesses have considerable latitude to define this expenditure as they see fit. It is well known that there are significantly weaker incentives to reduce capex than opex (particularly towards the end of the regulatory period).

Therefore distributors are able to maximize their shareholder returns (at the expense of users) by reclassifying their operating expenditure as capital expenditure. It can be no small coincidence that amongst all Australia's distribution businesses, comparing actual expenditure with allowed expenditure shows consistently better performance of opex rather than capex, i.e. generally consistent underspending of opex or close to level-pegging of opex, but usually massive overspending on capex (in the case of government-owned distributors) or relatively less underspending on capex than opex (for privately-owned distributors). Until such time as the AER has developed a reliable system of regulatory accounts that ensure consistent cost reporting by distributors, this concern will remain. For this reason, mainly, we suggest that the assumption that revealed costs are efficient in setting the starting point for the opex allowance, cannot be sustained.

5.4 Inadequate benchmarking

We can find no evidence in any of the published material provided by the AER or any of its consultants that any attempt has been made to have regard to the benchmark capex of an efficient distribution network service provider. As such, we conclude unequivocally that the AER has failed to implement its Rules obligations in respect of opex.

The AER claims to have benchmarked opex in its draft decision for Energex and Ergon. However, the AER says that it has only used it as a "top down test of more detailed bottom-up assessments" (p. 195).

The rest of this sub-section explains what the AER has done on opex benchmarking and evaluates this. All the useful information on the AER's application of benchmarking opex for Energex and Ergon is set out in Appendix I and J of their draft decision.

The main elements of the AER's opex benchmarking are summarised below and explained afterwards:[8]

1. The AER developed a composite scale variable as the explanatory factor in a single variable regression.
2. It then produced a scatter plot of total opex for 2007/8 against the composite scale variable for distribution network service provides in Australia, except those in Western Australia and the Northern Territory.
3. A linear ordinary least squares regression line on that scatter plot was drawn.
4. The AER drew conclusions on the basis of the data points for Energex and Ergon in relation to the regression line.

Composite scale variable

The underlying hypothesis in the AER's benchmarking is that the efficient total operating expenditure of a distributor varies as a function of the length of the network of the distributor and the number of customers of that distributor. This hypothesis was developed by the AER's consultants, Wilson Cook, for the AER's review of the price control for the New South Wales distributors.

These two expenditure drivers – length of network and number of customers – were then combined in a "composite scale variable". They were combined on the basis of the assumption that the size variable should be calculated as 3.3626 multiplied by

[8] This explanation of the AER's benchmarking is not available from the published material but rather is based on information specifically provided to us by the AER, in correspondence. The correspondence is not confidential and is available to EUAA members on request.

the length of the network and that the total number of customers should be multiplied by 0.1306.

The use of a composite scale variable has been adopted by the Office of Gas and Electricity Markets (Ofgem) in Britain in its benchmarking, although Ofgem's benchmarking included energy sales in a composite scale variable that was therefore calculated on the basis of three elements. In this sense, the AER's use of a composite scale variable is similar to aspects of the benchmarking methodology adopted by Ofgem.

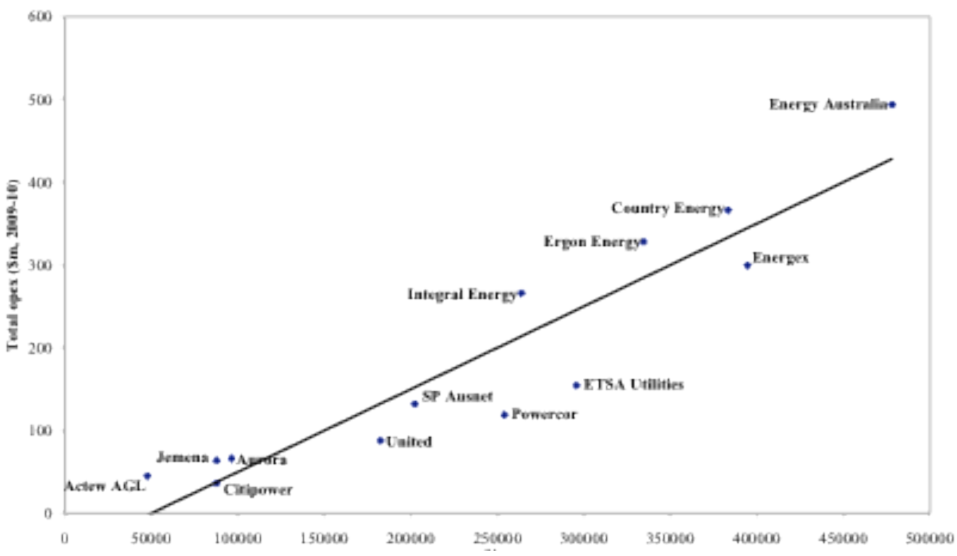
Scatter plot

The AER then plotted the Total Opex against the composite scale variable for all distributors (except those in Western Australia and the Northern Territory) for the year 2007/8.

Linear Regression

The AER then drew a straight line based on an ordinary least squares regression. In other words, a line that comes as close to all data points as possible. The AER emphasised in the Draft Decision and in subsequent correspondence with us, that the line is only taken to represent the line of best fit, not an estimate of the efficient benchmark, as required under the Rules. The scatter-plot, with the line of best fit is reproduced in Figure 11 below:

Figure 11. AER's opex scatter plot with regression



Drawing conclusions

The AER then noted that Energex was below the line of best fit and Ergon was above the line of best fit. In both cases, the AER made no change to its determination of the efficient opex as a result of these observations:

- In the case of Ergon, they dismissed the observation that Ergon was above the line of best-fit on the assertion that "… *it reflects the efficient allowance provided by the QCA, and the overspend has been justified by Ergon Energy.*

The AER also notes that the 2007–08 data is the most up to date available and has been subject to audit". (p. 159)

- In the case of Energex, they dismissed the observation that Energex was above the line but did not even attempt to explain why they had dismissed the observation.

5.5 Why does the AER's benchmarking fall short of its Rules obligations ?

We suggest that the AER's opex benchmarking falls short of its Rules obligations in four ways, summarised below and then explained in the rest of the subsection:

1. The AER has defined a role for benchmarking that is inconsistent with the Rules;
2. The AER has failed to define the benchmark efficient opex;
3. The AER has benchmarked historic expenditure;
4. The AER has failed to act on the outcome of its benchmarking.

The role of benchmarking

The AER played down the role of benchmarking, describing it merely as a "*top-down test of detailed bottom-up assessments*". As noted earlier, the Rules do not give the AER freedom to play down benchmarking, or any of its other capex or opex factors in this way. Specifically, the Rules identified benchmarking as one (of ten) factors that the AER is required to have regard to. We suggest that the AER does not have discretion under the Rules to define benchmarking as a subsidiary approach, merely for "top-down" testing of other methodologies. Benchmarking stands alone – just like the other 10 factors – and should be considered just like the other factors.

However, it should also be noted that the AER's approach to the use of benchmarking of total opex stands in contradiction to its approach to benchmarking of debt and equity raising costs. For these costs (which are counted as "uncontrollable opex"), the EUAA pointed out to the AER in its earlier submissions that as Government-owned entities, Energex and Ergon do not incur debt or equity raising costs since their State Treasury Department arranges their debt funding and the State Government is the sole shareholder in the businesses. In response, in the Draft Decision the AER pointed to its obligation to have regard to benchmarks in setting allowed opex, as justification of its use of benchmarks to determine the debt and equity raising costs for Energex and Ergon.

In the case of debt and equity raising costs, therefore, the AER had no regard to the other nine factors set out in the Rules – instead it only had regard to (private sector) benchmarks. Had it had regard to these other nine factors (or to benchmarks based on government-owned businesses), it would of course have been clear that Energex and Ergon don't incur any debt or equity raising costs.

In effect, therefore, the AER has had *exclusive* regard to benchmarking of debt and equity raising costs and ignored the other nine opex factors to which it is required to have regard. In this way, it is has justified increasing opex for Energex and Ergon by around $47m. However for the determination of the bulk of opex (the "controllable opex"), the AER has played down the role of benchmarking as "just one of ten factors" only to be used for "top-down" testing, and even then has ignored the information provided by its own benchmarking, as described below. In this case, in contrast to its approach to debt and equity raising costs, benchmarking is the only factor it has failed to have regard to?

Failed to define benchmark efficient opex

The Rules require the AER to determine the benchmark opex of an efficient network service provider. The AER has failed to do this. Instead, as noted above, the AER emphasised in the Draft Decision and in subsequent correspondence with us, that the line it has drawn is simply the line of best fit, not an estimate of the efficient benchmark – as required under the Rules. Having failed to define what the benchmark efficient opex is, it is impossible for the AER to claim that it has had regard to it.

However, there are other important issues to draw attention to here. The AER's line of best fit – the "ordinary least squares", is conceptually a line that represents the average relationship between opex and the composite scale variable. In other words, it represents the average efficiency. Although the AER has been at pains to point out that its line does not represent the efficient frontier, it has used its line to draw conclusions about the relative efficiency of Energex and Ergon . As such, as much as it disavows it, the AER has indeed used the ordinary least squares line as the key to its "benchmarking".

This is wrong both conceptually and in practice. Conceptually, the efficient benchmark or efficient frontier is meant to represent the efficiency of the *leading* service providers, not the *average* service provider. In every application of benchmarking that we are aware of, and in all surveys of international experience in benchmarking where regression techniques are used (see (Pollitt & Jamasb, 2000, p. 7), (Mehdi, Aurelio, & Massimo, 2007, p. 9), (Haney & Pollitt, 2009, p. 17), it is the "corrected" ordinary least square that is used, not the ordinary least square.[9] The "correction" establishes the benchmark based on the leading service providers, with the only point of contention being whether "leading" is defined as the most participant, or the top decile or upper quartile.

The AER has benchmarked historic expenditure rather than expenditure for the coming regulatory period

The AER's benchmarking is based on expenditure for the year 2007-8. This is three years before the start of the regulatory control period to which the current price/revenue controls relate. It is legitimate to build the dataset for all comparators at this date, but the expenditure that should have been benchmarked, is the allowed expenditure for the coming regulatory period (as is required by the Rules), not the expenditure by Ergon and Energex in 2007/8.

[9] We note for completeness that Pollitt, M. G., & Jamasb, T. (2000) mention ordinary least squares approaches but this is in the context of regulatory incentives, not efficiency benchmarking.

The AER has failed to act on the outcome of its benchmarking

Notwithstanding our criticism that the AER's benchmarking is inadequate, they have nevertheless failed to act on the information contained in their own benchmarking. Specifically, the AER concluded that Ergon's opex was less efficient than the ordinary least squares line it drew, while Energex was above this line (and hence presumably more efficient). In both cases the AER made no changes to its allowed opex to account for this, but instead asserted, without reason, that these results could be dismissed.

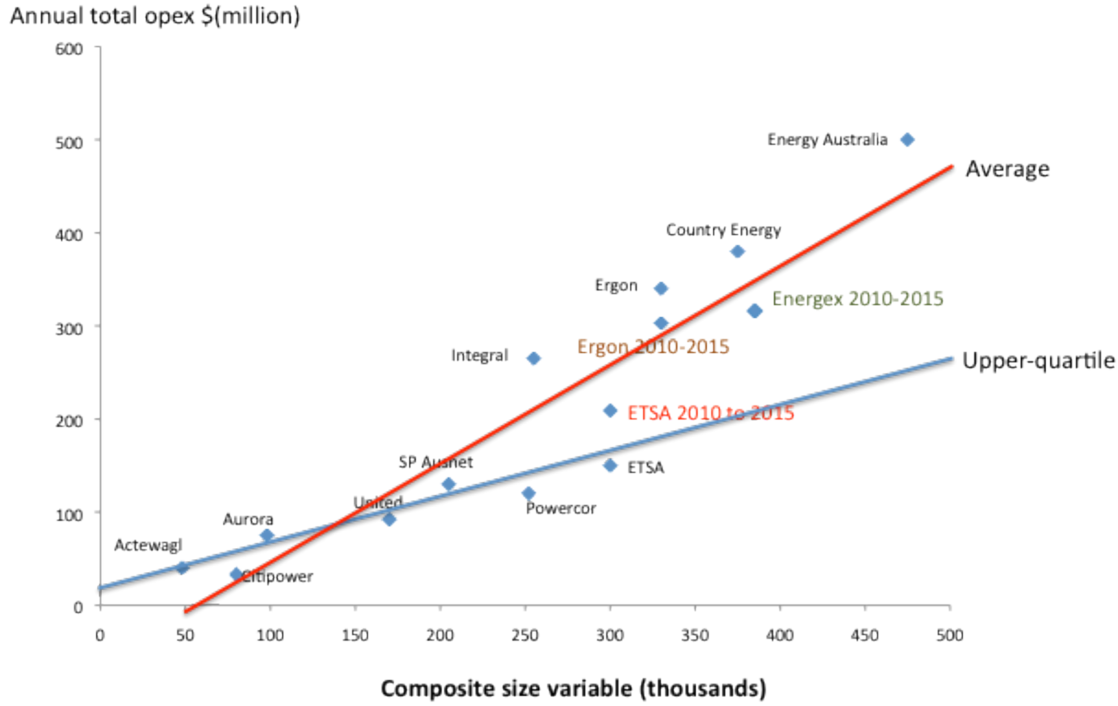
5.5.1 How would the price/revenue control decisions differ if the AER had properly had regard to the efficient benchmark?

We have developed our own analysis of an efficient benchmark. There are a few key points to this analysis:

- We have used the AER's dataset – specifically their own calculation of the composite scale variable and revenues for all distributors for 2007/8.
- We have used the average revenues for the coming regulatory period (as required under the Rules) for Energex and Ergon.
- We have chosen an efficient frontier based on the top-quartile performance. As noted earlier, a "corrected" ordinary least square is needed to establish an efficient frontier. The choice of the upper-quartile for the regression conforms with the approach that Ofgem has used in Britain.

The results of this regression are illustrated in Figure 12. The red line is the AER's ordinary least squares (average), while the blue line is the upper-quartile (corrected) ordinary least squares that we suggest is the appropriate benchmark. With the AER's approach, their decision of the average allowed revenue for Ergon is slightly less efficient than their benchmark, and Energex is slightly more efficient than their benchmark. By comparison, using the upper-quartile as the benchmark, the AER's draft decision shows that the allowed revenue for Energex and Ergon are all now far from the benchmark.

Figure 12. Upper quartile and least squares regression



We have quantified the opex reductions that would be needed to bring Ergon and Energex's average allowed opex for the coming regulatory period in line with the benchmark, in the table below. The first column is the average allowed opex based on the AER's Draft Decision. The second column is the benchmark level of opex assuming these businesses were required to raise their efficiency to the upper quartile. The third column is the reduction in opex required to bring the businesses' opex expenditure in line with the benchmark. The last column is the expenditure reduction stated as a percentage of the AER's draft decision allowance.

Table 1. Opex reductions required

	Average annual allowed total opex for coming regulatory period ($million)	Upper-quartile benchmark opex ($million)	Difference between draft decision and benchmark ($million)	% reduction
Ergon	$303	$168	$134	44%
Energex	$317	$196	$121	38%

We call on the AER to say why it has not defined a benchmark for opex, and specifically why it has chosen not to set a benchmark based on upper-quartile performance ? In addition, we expect the AER to demonstrate how it had regard to this information in setting Energex and Ergon's opex allowances.

5.6 Debt and equity raising costs

We disagree with the AER's proposal to permit debt and equity raising costs totalling $47m to be included in the opex of Energex and Ergon. Energex and Ergon are government-owned distributors and the Queensland Treasury arranges its debt and provides its equity. Neither Energex nor Ergon incur any of the costs associated with debt and equity raising that non-government owned distributors incur. For example, it has no need for prospectuses, under-writing fees, payments to credit rating agencies, payments to debt and equity arrangers and so on. It is not reasonable that energy users are being asked to pay Energex and Ergon $47m to compensate them for costs **which they simply do not incur**. This is at odds with the National Electricity Objective and the AER's capex and opex factors. The AER must rectify this in its final decision or provide a full explanation of why these costs are justified and how they will be incurred by the two distributors.

We note that the AER's approach to setting debt and equity raising costs is that it has exclusively adopted benchmarking in relation to these costs.

Whist we support its use, contrary to what the Chairman of the AER has publicly said, the EUAA has never suggested that the AER should rely only on benchmarks to set expenditure allowances. The EUAA's position is that the AER should have regard to all the other factors mentioned in the Rules. In the case of debt and equity raising costs, the AER had no regard to the other nine factors set out in the Rules. We think it should have, and the Rules require it.

Furthermore, the AER's approach to the use of benchmarking for debt and equity costs makes the contrast with its approach to the use of benchmarking total opex and capex all the more stark. For debt and equity raising costs, where a proper application of the various opex factors would reveal no justifiable expenditure , the AER chooses to turn a blind eye to these factors and instead rely on benchmarks based on privately-owned distributors. And yet, for total opex and capex the AER suggests benchmarking has little relevance? We have difficulty in understanding the AER's logic and the apparent inconsistency with which they apply the opex factors.

6 Comment on pass-throughs

We do not support pass-throughs as a matter of principle and believe that they will always be asymmetric in favour of the network businesses given their information advantages. Consequently, during any regulatory control period it is highly likely that only cost increases will be the subject of pass through and any cost reductions that emerge will almost certainly never be passed through.

Whilst the National Electricity Rules and the National Electricity Law permit pass through and it has been a feature of energy network regulation for some time, this asymmetry in outcomes ought to be recognised in the assessment of pass through arrangements. We urge the AER to also consider this matter in the broader context of its regulation of network businesses, including the option of a Rule change that will lead to more balanced outcomes in future.

In this context we note that the application of economic regulation to energy networks in Australia has been founded on the principle that the outcomes ought to mimic those found in competitive markets. With regard to pass-throughs this clearly has a limited application. In competitive markets, pass through only applies where costs are the result of factors outside the control of the business and then only if the business is in a position to be able to pass through these costs. In the case of regulated businesses, this needs to be recognised by the regulator with a sceptical eye on the incentives for "strategic behaviour" by the regulated business.

The EUAA notes that the AER, in the draft determination (p331) shares our concerns regarding pass though risk avoidance as it has stated that the application of section 7A (3) of the National Electricity Law "*It is limited in its application as it has the potential to undermine the incentive to effectively manage risk in a least cost manner*". We welcome this comment.

Within the context of the regulatory approach, the EUAA has concerns over the Queensland distributors' proposed pass-through events. Energex and Ergon have proposed pass through events which are of concern to users and we would urge a rigorous assessment of them by the AER to determine their validity. The EUAA would like to draw particular attention to:

- CPRS event: a distribution business has minor costs that it would incur as a result of the CPRS. All businesses in Australia will have some carbon impost and many will have to manage the risks associated with these costs internally and will have limited scope to pass them on to customers. Giving the distributors' allowances to pass on costs associated with the CPRS could eliminate any incentive on them to reduce these costs.

- Feed in Tariff Event: the EUAA questions the feed in tariff event which requires DNSPs to make payments for electricity generated by solar power systems and put on to the grid. These feed in tariffs will be part of business as usual over this period and into the future and should be managed by the business appropriately. The EUAA also acknowledges that both businesses have forecast expenditures for feed-in tariffs in relation to their opex. The AER has determined that a pass through cannot be accepted if there is a provision for these costs to be factored in opex or capex. As such, the AER needs to ensure that a feed-in tariff pass through does not simply result in double counting.

- <u>Smart Meter Event</u>: The EUAA also strenuously objects to the smart meter pass through allowed by the AER. The Queensland DNSPs should have to manage obligations under a smart metering program as efficiently as possible and should not be able to pass on these costs under the cost pass through provisions in the NER and NEL. The AER allowed a smart meter event as a specific pass through as it ruled that it met the criteria for a general nominated pass through event. The AER stated that while it was highly likely to occur the costs associated with the event were very difficult to forecast. The EUAA points out that the costs associated with a smart meter rollout are not difficult to forecast as a smart meter rollout is currently underway in Victoria and there is a transparent cost associated with the rollout. The AER has a listing of a number of costs in its revenue determination for the Victorian DNSPs when it assessed the revenue requirements for these businesses. Furthermore the costs associated with Victoria's smart meter program were assessed under a similar process to the regulatory revenue determination process. In Victoria the costs of the smart meter rollout had the businesses recovering costs through a capex, opex and allowed revenue approach that was undertaken by the AER. It is not unreasonable to suggest that the AER should take the same approach for smart meter rollouts in other States.

7 Comment on service standard incentives

The EUAA is unhappy with aspects of the performance targets under the Service Target Performance Incentive Scheme (STPIS). The AER sets targets using averages that take into account historic under-performance in the setting of new targets. Energex and Ergon Energy's historic SAIDI and SAIFI trends point to improving performance and thus setting the targets at historic average provide the opportunity for windfall gains on performance improvements that have already been achieved, rather than those which have yet to be achieved. The most appropriate methodology would be to have established data service classes across the distribution sector and set the target based on an upper quartile benchmark. In the absence of such data – and we are yet to be convinced that such data is not available – we suggest that the AER sets the target based on trend lines of the Queensland distributors' historic performance.

The EUAA has raised the issue of power quality in its submissions to the New South Wales and Queensland regulatory reviews. The AER stated in its draft determination that the EUAA considered the STPIS a 'welcome development' and that quality of supply was an important factor for its customers. The STPIS leaves open the potential for power quality to be included in a service target scheme. Furthermore, as we noted in the submission to the NSW DNSP review, the AER has promised to consult with the DNSPs (and we would hope also end users), in setting the values for performance targets for the 2014-19 period.[10] The EUAA requests that the AER begin this consultation process with the businesses and end users for power quality to be included in the STPIS for the 2014-2019 regulatory period and would suggest looking at the scheme currently operating in South Australia as a good starting place.

[10] EUAA, *Submission to Australian Energy Regulators' Draft Decision & Revised DNSP Proposals – Review of NSW Distributors' Regulatory Proposal*, p. 21

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